(**Without Reference to File**)

SENATE THIRD READING
SB 846 (Dodd)
As Amended August 28, 2022
2/3 vote. Urgency

SUMMARY

Extends the operation of the Diablo Canyon Power Plant (DCPP) by five years. Provides expedited mechanisms to facilitate the relicensing of DCPP, including: providing an initial loan to Pacific Gas & Electric (PG&E) of up to $600 million; limiting state agency review of applications related to the DCPP extension to 180 days; exempting DCPP from CEQA; and explicitly authorizing ratepayer funding for ongoing costs, including $100 million paid annually to PG&E shareholders.

Major Provisions

1) Appropriates $600 million from the General Fund to the Department of Water Resources (DWR) which may be loaned to PG&E to facilitate the DCPP extension. Additionally:

    a) Declares the DCPP extension shall be no later than November 1, 2029 for Unit 1, and November 1, 2030 for Unit 2.

    b) Limits the initial loan allocation by DWR to $350 million, and requires a written expenditure plan be submitted to the Joint Legislative Budget Committee (JLBC) by DWR prior to any additional funds being released.

    c) States the legislative intent that up to $1.4 billion be made available for this loan.

    d) Prohibits DWR from releasing the funds in a lump-sum, rather disbursement of the loan must occur in tranches contingent upon a semiannual review of costs.

    e) Creates the Diablo Canyon Extension Fund in the State Treasury for these purposes.

2) Requires any loan between DWR and PG&E to include:

    a) Covenants by PG&E that it will:

        i) Take all steps necessary to secure a grant or other available funds from the federal government in order to repay the loan;

        ii) Allocate to ratepayers 90% of all revenues received from federal and state tax credits or incentives, except for federal funds expressly for power plant operation extensions.

        iii) Indemnify DWR and the state for liability associated with DCPP.

        iv) Conduct an updated seismic assessment.

        v) Commission a study by independent consultants to catalog and evaluate any deferred maintenance at DCPP and to provide recommendations as to any risk posed by the

deferred maintenance, potential remedies, and cost estimates and timeline for those remedies.

vi) Report to the California Energy Commission (CEC) by March 1, 2023 on the available capacity of existing wet and dry spent fuel storage and the forecasted amount of spent fuel that will be generated by the plant both through the current retirement dates and through the extended dates.

b) Built in off-ramps, which include:

i) Immediate termination or suspension of the loan if:

(1) PG&E is not deemed eligible by the Department of Energy (DOE) for a federal funding program by March 1, 2023.

(2) DWR determines PG&E has not obtained the necessary license renewals, permits, and approvals, or that the conditions and timeframes for such licenses are too onerous or will generate costs that exceed $1.4 billion.

(3) CPUC determines the DCPP extension is not cost-effective or is imprudent, or both.

(4) CEC determines that the statewide energy forecasts do not show reliability deficiencies if DCPP is retired by 2025, or that extending DCPP to at least 2030 is not necessary for meeting any potential deficiency.

(5) DCPP retires early and unexpectedly.

ii) Immediate repayment of the loan if PG&E fails to:

(1) Submit a timely and complete application for funding to the DOE for eligibility in the Civil Nuclear Credit Program.

(2) Disclose to DWR any known safety risk, seismic risk, environmental hazard, or material defect that would disqualify its DOE grant application or otherwise disallow or substantially delay any necessary approvals for an extension.

(3) Retain ownership of DCPP.

iii) If the costs of operations at any time during the DCPP extension exceed cost limits provided in the loan, the CEC shall reevaluate the cost-effectiveness of prolonging DCPP's operations.

iv) If the costs of seismic safety or any other safety modification required during the consideration of relicensing DCPP, the CEC shall evaluate whether the extension remains a cost-effective means of meeting statewide mid-term reliability before any subsequent authorization or appropriation of funds by the Legislature.

c) A monthly $7 per megawatt-hour (MWh) payment for 2023-2025, contingent upon the operator's ongoing pursuit of a DCPP extension and DCPP's continued safe and reliable

operation. This roughly totals to ~$350 million, assuming an annual production of 16,500 gigawatt-hours from DCPP.[1]

d) Express prohibition against loan proceeds going to shareholder profits or paid out as dividends, or dividends being deemed eligible costs under the loan.

3) Exempts any loan between DWR and PG&E from the California Environmental Quality Act (CEQA), and categorizes DCPP as an "existing facility" for purposes of CEQA, thereby eliminating environmental review of any project on the DCPP site

4) Within 180 days after the loan begins, requires DWR, in collaboration with the California Public Utilities Commission (CPUC), to conduct a semiannual true-up review of PG&E's loan proceeds. The review must demonstrate PG&E did not retain any loan revenues for shareholders, determine whether eligible costs were reasonable, and ensure the CPUC had not authorized rate recovery of the same costs.

5) Expedites to 180 days final action by any state agency that is necessary to authorize a DCPP extension.

6) Permits DWR to enter into agreements or contracts with the CPUC or other agencies, engage with private consultants or arrangements as necessary, hire personnel, and disburse funds to reimburse itself. Exempts these DWR contracts from competitive bidding or state contracting requirements.

7) Excludes DCPP after 2024 for Unit 1 and 2025 for Unit2 from the integrated resource plan (IRP) requirements for all load-serving entities (LSEs = investor owned utilities (IOUs), community choice aggregators (CCAs), and electric service providers (ESPs)). Likewise updates IRP requirements so that sufficient resources needed to avoid unplanned energy shortfalls are procured.

8) Excludes DCPP after August 26, 2025, from meeting the statewide 100% clean energy goal enacted under SB 100 (De León, Chapter 312, Statutes of 2018), and establishes a rebuttable presumption at the CPUC for the need of transmission projects approved by CAISO, if certain conditions are met.

9) Codifies the Independent Safety Committee for Diablo Canyon (ISCDC), which was established under a 1988 CPUC decision. The Safety Committee conducts annual examinations of DCPP, including site visits.

10) Invalidates a 2018 CPUC decision detailing the retirement of DCPP and its decommissioning plan, and orders the CPUC to reopen PG&E's 2016 application to retire DCPP in order to implement its extension. Requires any funds already disbursed and committed under the 2018 decision to be unaffected, and continues the employee retention program into the years of extended operation. Requires the CPUC, within 120 days of this bill's chaptering but no later than December 31, 2023, to authorize PG&E to take all necessary actions to extend DCPP to October 31, 2029, for Unit 1 and October 31, 2030, for Unit 2.

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[1] California Energy Commission, "2021 Total System Electric Generation," https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation. Accessed on 08/30/2022.

11) Provides off-ramps for the CPUC to retire DCPP earlier than authorized in this bill if:

    a) based on ISCDC reports, the costs needed for seismic safety or other needed upgrades are too high to justify incurring;

    b) the conditions of PG&E's license renewal requires expenditures too high to justify incurring;

    c) the DWR loan is terminated;

    d) new renewable energy and zero-carbon resources are built, interconnected, and determined to be adequate to substitute DCPP; and

    e) the federal Nuclear Regulatory Commission (NRC) does not renew DCPP's license.

12) Prohibits any funds needed by PG&E to prepare for any extended license from being paid for by ratepayers, and instead directs those costs to be covered by the DWR loan. Additionally prohibits the CPUC from increasing the costs to PG&E ratepayers for operations and maintenance of DCPP prior to the extension (2022-2025).

13) Explicitly authorizes ratepayer funds for DCPP operations during the extension (2025-2030), and specifies the rates must:

    a) Be reasonable and necessary to operate DCPP beyond the current expiration dates, after adjustment for market revenue and any tax credits. These rates will be set by the CPUC. Additionally requires recovery of these costs and expenses to be forecast—rather than reimbursed expenses – with a subsequent true-up of the forecast cost to actual costs. If actual costs are below 115% of forecast cost, the CPUC is prohibited from reviewing the reasonableness of those costs.

    b) Be recovered on a fully nonbypassable basis from customers of all LSEs subject to CPUC jurisdiction ("LSE ratepayers"). This includes CCA ratepayers, as well as those of other IOUs like Edison and SDG&E. Also requires rate recovery be based on each customer's gross consumption of electricity regardless of net metering status or purchase of electricity from an alternate provider.

    c) Include a $6.50/MWh volumetric charge for all non-PG&E LSE ratepayers, and a $13/MWh charge for all PG&E ratepayers for each MW generated by DCPP during the extension. This roughly totals to ~$321 million annually, assuming an annual production of 16,500 gigawatt-hours from DCPP.[1]

        i) Stipulates the compensation from this volumetric charge cannot be paid to shareholders, but rather must be used to first meet needs at DCPP and then to accelerate, or increase spending on, critical priorities including interconnections of resources, grid modernization, building decarbonization, workforce and customer safety, education, or increasing resiliency.

        ii) Prohibits PG&E from earning a rate of return for any of the above expenditures, so that no profit is realized by PG&E shareholders.

iii) Prohibits PG&E from increasing existing public earning per share guidance as a result of compensation provided under this volumetric charge.

d) Include a $100 million annual fixed payment, which may be reduced by half should DCPP have extended service outages, as specified. Regardless of the duration of the outage, PG&E would still receive an annual minimum payment of $50 million.

   i) This payment could be used as direct compensation for shareholders.

e) Include a $25 million per month fee to be collected until a total of $300 million has been accrued. This funding is authorized to pay for replacement power costs if PG&E fails to manage DCPP reasonably resulting in an unplanned outage. If used, the $25 million per month collection will resume until $300 million is again accrued. Stipulates any outstanding funds remaining in the account shall be returned to only customers in PG&E territory, even though the charge was collected from all LSE ratepayers.

f) Stipulates all costs for DCPP beyond 2025 shall be recovered as an operating expense and are not eligible for inclusion in PG&E's ratebase. In other words, PG&E does not earn a rate of return for DCPP during the extension.

g) Directs the CPUC to determine the amount to be borne by all LSE ratepayers of reasonable additional decommissioning costs and costs to engage the independent peer review panel.

h) Provides that market revenues from DCPP power sales that exceed annual costs and expenses, including for the above charges, be credited to customers in PG&E's service territory. For customers outside PG&E territory, market revenues may be used to credit customers to neutral. If market revenues remain in the final year of DCPP extension, those revenues shall be the sole source of the DWR loan repayment except if federal funds remain to pay the loan. Stipulates any excess funds remaining from market revenues shall not be paid out to shareholders.

i) Requires if DCPP is not eligible for the DOE nuclear credit program, then the above provisions are inoperative and the CPUC is directed to undertake ordinary ratemaking.

14) Permits the CPUC to fine PG&E up to $300,000 per violation—3x the current penalty cap—if PG&E requests recovery of costs that were previously authorized. In other words, no double-counting is allowed.

15) Requires numerous reports or workshops to analyze future reliability or to justify the need of a DCPP extension, including:

a) By December 15, 2022, and quarterly thereafter, a joint assessment by the CEC and the CPUC on reliability that evaluates the electrical supply and demand under various risk scenarios for five and ten years into the future.

b) By September 30, 2023, a CEC cost comparison of whether a DCPP extension versus other feasible resources is consistent with statewide greenhouse gas (GHG) reduction goals.

c) Within 180 days of PG&E filing for federal funding to extend DCPP, a determination by the CEC, in consultation with the CPUC and the California Independent System Operator (CAISO), of whether the state's electricity forecasts for 2024-2030 show potential for reliability deficiencies if DCPP is not extended, and whether such an extension is prudent.

d) By July 1, 2023, an annual assessment by the CEC, in coordination with the CPUC and CAISO, of the operations at DCPP, including outage information, operational costs, average revenues, worker attrition, and the plant's contribution to resource adequacy (RA) requirements.

e) At least 30 days before any final action of a state agency on the DCPP extension, a joint public workshop facilitated by the Secretary of Natural Resources Agency shall be held to consider public input concerning the environmental impacts and mitigation of the DCPP extension.

f) By January 31, 2023, a report to the JLBC by the Secretary of the Natural Resources Agency, in coordination with various state agencies and the CPUC, identifying all actions necessary for the DCPP extension.

g) An annual report by the CPUC, in coordination with the CEC, CAISO, and DWR, on the status of new resource additions and revisions to the state's electric demand forecast, and the impact of these updates on the need for keeping DCPP online.

16) Requires the CEC, in consultation with the CPUC and CAISO, to adopt a goal—and update the goal biennially—for load shifting to reduce net peak electrical demand.

17) Continues until 18 months after the permanent closure of DCPP the ratepayer-funded Nuclear Planning Assessment Special Account that pays for local and state costs of emergency planning for a nuclear accident. Additionally halts the disbursement, except to refund ratepayers, from the Diablo Canyon Nuclear Decommissioning Non-Qualified Trust.

18) Requires the CPUC, in consultation with relevant federal and state agencies and Native American tribes, determine the disposition of DCPP's property in a manner that best serves the interests of the local community, ratepayers, tribes, and state. States the Legislature's intent that existing land transfer efforts are not impeded by the DCPP extension.

19) Extends the waiver of DCPP from the State Water Board's once-through-cooling policy, which since 2010 has been in place to phase out the use of once-through-cooling technology in powerplants given their marine impacts.

20) Additionally appropriates the following:

a) Up to $5 million in General Fund to the CEC or CPUC for workload to implement this bill.

b) $1 billion in future year to support a Clean Energy Reliability Investment Plan developed at the CEC to support programs and projects to accelerate the deployment of clean energy resources, demand response, assist ratepayers, and increase energy reliability.

c) $160 million in future year funding for a land conservation development plan to support environmental enhancements and access to DCPP lands and local economic development.

21) Makes the provisions of this bill severable, and declares this bill an urgency statute to take effect immediately.

COMMENTS

The Diablo Canyon Nuclear Power Plant. DCPP is California's only remaining operating nuclear power plant. It consists of two units: Unit 1 is 1,073 MW which began operation in May 1985; Unit 2 is 1,087 MW which began in March 1986. The plant produces approximately 8.5% of California's in-state electric generation. Currently, DCPP is licensed by the federal Nuclear Regulatory Commission to operate until November 2, 2024 (Unit 1) and August 26, 2025 (Unit 2). Currently, the DCPP averages about 16,500 gigawatt hours (GWh) annually in net generation.[2] DCPP reportedly took 18 years and over $5.5 billion to construct, well above the estimated $400 million initially projected.

DCPP sits on approximately 900 acres adjacent to the Pacific Ocean between Avila Beach and Montaña de Oro State Park in San Luis Obispo County. The plant employs roughly 1,500 employees who help operate the facility. DCPP itself generates millions in property tax revenue, which mainly benefits local schools.[3] A study, commissioned by PG&E, of the economic benefits of DCPP concluded that operation of DCPP in 2011 contributed, directly and indirectly, over $900 million to the local economy, including many of the regions high-paying, year-round jobs.[4] The DCPP is a major contributor to the economy of San Luis Obispo County and northern Santa Barbara County as both a source of tax revenue and employment.

On June 28, 2016, the State Lands Commission voted to approve a lease extension for DCPP to 2025. A week prior to the vote, PG&E announced a Joint Proposal with labor and environmental organizations that would result in the closure of the plant by 2025 and "increase investment in energy efficiency, renewables and storage beyond current state mandates." In August 2016, PG&E filed an application with the CPUC submitting the Joint Proposal to review and request for approval of the replacement power provisions, an employee retention program, and other elements. The application sought over $1 billion in ratepayer funds to pay for the costs associated with the proposal. In the fall of 2017, the CPUC voted to approve the retirement of the DCPP, including approval for some of the elements of the Joint Proposal. Specifically, the CPUC approved $222.6 million in rate recovery for costs associated with the employee retention ($211.3 million) and retraining ($11.3 million). The CPUC also approved $18.6 million for license renewal activities. However, the CPUC denied elements of the Joint Proposal.

In response, SB 1090 (Monning, Chapter 561, Statutes of 2018) was introduced in the Legislature and directed the CPUC to require the use of ratepayer funds for activities the CPUC had previously denied, including: an additional 10% augmentation to the already-approved 15%

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[2] California Energy Commission, "2021 Total System Electric Generation," https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation. Accessed on 08/30/2022.
[3] San Luis Obispo County Comprehensive Annual Financial Report for Fiscal Year 2013-2014. http://www.slocounty.ca.gov/Assets/AC/Digital/Financial/CAFR/2013-14CAFR.pdf
[4] *Economic Benefits of Diablo Canyon Power Plant: an economic impact study.* June 2013.

annual employee retention bonuses (for a total of 25% annual retention bonuses), and the requirement that replacement power be GHG-free, as well as, approving funds for the local community. The CPUC issued a new decision in 2018 following the passage of SB 1090. That legislation and the subsequent CPUC decision has guided the last four years at DCPP, as the plant actively prepares for its planned decommissioning.

This bill would halt the decommissioning effort, invalidate the 2018 CPUC decision (while retaining the authorized funding), and require the CPUC to reopen PG&E's application to retire DCPP. Additionally this bill requires the CPUC to authorize, within 120 days of its chaptering, PG&E to take all necessary actions to extend DCPP to October 31, 2029, for Unit 1 and October 31, 2030, for Unit 2, a little over five years past their current retirements. The need for such action largely hinges on: 1) ensuring reliability during the most extreme events on our electricity grid; and 2) the possibility of PG&E drawing down over $1 billion federal dollars to pay for relicensing.

Need—Will the Lights Go Out? The last two summers in California have had close calls in keeping power on, as the supply of resources serving our electricity grid struggled to match demand. Last July, during an extreme heatwave across California, a major transmission line at the California-Oregon border was impacted due to a nearby wildfire, bringing the CAISO precariously close to calling for rotating outages. This coming Labor Day weekend, a western-wide heatwave is forecast to drive temperatures into the triple digits throughout the state. Such heat not only drives demand on the system—in large part due to more air conditioning use—but impacts our supply through both a reduction in our imports as well as a reduction in output from older, in-state resources that become inefficient in higher temperatures.

Rotating outages are the last, worst tool available to grid operators and energy planners to manage any supply and demand imbalance. They are the tool everyone seeks to avoid, as outages can have devastating economic and health impacts, compounded under extreme weather events like heatwaves or fires. In California, these larger climate events are occurring alongside ambitious renewable energy integration[5] and anticipated large increases in demand.[6] These changes could lead to more prevalent and complex challenges beyond what was experienced in the summers of 2020 and 2021.

Recognizing this need and the insufficient pace at which new resources were being developed, the CPUC issued historic procurement orders in June 2021, requiring utilities to purchase 11,500 MW of new electricity resources to come online between 2023 and 2026.[7] This is in addition to a 2019 procurement order of 3,300 MW by 2023.[8] These orders are meant to be fulfilled with preferred resources, such as distributed energy resources, renewables, and zero-emission sources. The procurement orders represent the largest capacity procurement ordered at a single time by the CPUC. The CPUC reports that 2,650 MW of incremental capacity has come online in the

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[5] Over the next decade, the state was planning to retire both DCPP and a fleet of privately-owned, once-through-cooling natural gas power plants (totaling thousands of MWs in 2019) and replace these resources with clean energy. Additionally, the state established the policy goal of meeting all retail electricity supply with a mix of Renewables Portfolio Standard (RPS)-eligible and zero-carbon resources by December 31, 2045, for a total of 100 percent clean energy (SB 100, De Leon, Chapter 312, Statutes of 2018.
[6] Arising from deep decarbonization efforts in the transportation and building sectors
[7] D.21-06-035
[8] 19-11-016

first four months of 2022 alone.[9] However, the COVID pandemic has led to global shutdowns and subsequent supply chain constraints occurring alongside international tariff disputes, resulting in a chilling of some renewable energy development. The Newsom administration reports a roughly 40% delay in energy projects for 2022, greatly increased from the historical average of 20% delay.

Following these summers of grid constraints and the present challenges in energy resource development, the state's energy leaders were led to examine every possible option for ensuring reliability in the summer of 2022 and beyond. In April of this year,[10] Governor Newsom commented on the possibility of extending operations at DCPP. Since the Governor's announcement, much reporting and discussion – including a California Energy Commission-led workshop earlier this month[11] - have presented the need, potential, and large hurdles to extending operation at DCPP. Despite these efforts, it remains unclear whether the scenarios shared by the Newsom administration accurately portray future realities, or are unnecessarily conservative and costly.

For instance, current analysis by the CEC shows a ~1,800 MW shortfall of resources in 2025 if DCPP goes offline. This occurs even if all the scheduled procurement ordered by the CPUC to replace Diablo shows up on time. This shortfall does not guarantee a power outage, but it does indicate that one is very likely, especially during certain hours on certain hot days.[12] If fire and climate risk or supply chain constraints are factored into the analysis, the shortfall rises to ~6,500 MW, almost 3x the capacity of DCPP.

As a result of these updated energy forecasts, the Legislature passed funding for a Strategic Reliability Reserve (SRR) in June.[13] The legislation tasks DWR with undertaking an intervention it has only done once before, during the Energy Crisis of 2000-2001, of purchasing energy resources, not necessarily clean ones, to help ensure grid reliability in the near-term. The June budget appropriated over $2 billion to support the SRR, with $550 million to support distributed backup and utility-scale assets to support reliability.[14] However, according to the state's energy agencies, this historic action did not fully alleviate the reliability issues, especially in the mid-term (2024-2026) when DCPP and coastal natural gas plants are scheduled to come offline.

With the new SRR, contingency measures enacted in previous summers,[15] and a 40% delay in installed generation assumed during the next two years, the agencies' analysis showed sufficient resources to cover a high electrification scenario with a 22.5% planning reserve margin. A shortfall was only present if an additional 4 GW of power was deemed lost due to "fire risk;" i.e. the potential for a fire to knock out a large capacity transmission line in the midst of another grid

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[9] As reported by the CPUC to this committee in April, 2022.
[10] Roth, S. "California promised to close its last nuclear plant. Now Newsom is reconsidering." *Los Angeles Times*; April 29, 2022.
[11] "Joint-Agency Workshop – Diablo Canyon Power Plant"; California Energy Commission; Friday, August 12, 2022; remote access only; https://www.energy.ca.gov/event/workshop/2022-08/joint-agency-workshop-diablo-canyon-power-plant
[12] September is a common month to consider for grid planners to consider this scenario.
[13] AB 205, Committee on Budget, Chapter 61, Statutes of 2022.
[14] "Final Version, Budget Act of 2022 Preliminary Summary"; https://sbud.senate.ca.gov/sites/sbud.senate.ca.gov/files/Final%20Version%20Preliminary%20Summary4.YS_.pdf
[15] Such as placement of gas- or diesel-fired back up generators, demand response measures for large consumers, and fuel switching at ports.

event, similar to what occurred in July 2021. The Newsom administration characterizes these scenarios as realistic—neither best nor worst case. But it is worth underscoring that the reliability argument for DCPP remaining online manifests only under the circumstance that an additional large MW loss to the system occurs atop already tight supply, something the SRR and contingency measures are expected to help alleviate.

Need—PG&E's DOE application. The Newsom administration has noted the opportunity for DCPP's operator, PG&E, to access DOE funding from the Infrastructure Investment and Jobs Act (IIJA) of 2021 to help offset some of the cost of DCPP's extension. The IIJA created a $6 billion federal investment, the Civil Nuclear Credit Program (CNCP), to help preserve existing nuclear reactors scheduled to close.[16] DCPP was originally not eligible for the CNCP, but DOE updated their guidance in June to make it eligible.[17] The current application deadline is September 6, 2022. As part of the application, nuclear operators must not only show an economic loss—to justify needing a federal subsidy to remain open—but also submit a detailed plan describing how operations would be sustained without receiving additional subsidies.[18]

DCPP currently operates at a net profit, providing roughly $150 million annually to PG&E shareholders.[19] Therefore, an alternative arrangement must be constructed to enable DCPP to apply to the CNCP. This bill provides the mechanism via a $600 million loan from DWR,[20] which PG&E can mark as a loss on its balance sheet, as the bill prohibits ratepayer funds from being spent to pay back the loan.

Additionally, this bill authorizes an unprecedented rate structure for DCPP should the facility receive an updated license to remain operational beyond 2025. The rate structure, which totals into the hundreds of millions per year in charges and fees, has been characterized by the Newsom administration as necessary for PG&E's CNCP application, as that application must provide a plan for sustained operations. However, it remains unclear why PG&E being a regulated utility—with a pool of captured customers and a constitutional protection that they recover just and reasonable costs—does not provide enough certainty that DCPP operations would be adequately funded during the extension. The Newsom administration points to the notoriously long waits for CPUC ratemaking decisions, noting there is not enough time to resolve these issues prior to PG&E's September 6th DOE filing. However, the CNCP application guidance does not require PG&E show a guaranteed funding stream, just that PG&E provide a *plan* to sustained funding. Why the historic record of PG&E being authorized to recover almost $1.2 billion annually from ratepayers for DCPP operations[21] is insufficient for this purpose remains an outstanding question.

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[16] https://www.energy.gov/ne/civil-nuclear-credit-program
[17] Changed CNCP guidance from the powerplant needing to receive "50% or more of total revenue" from a competitive electricity market" to "a material amount of its total revenue." See: "To aid Diablo Canyon, feds propose changes to nuclear credit program;" *Nuclear News*; June 21, 2022; https://www.ans.org/news/article-4071/to-aid-diablo-canyon-feds-propose-changes-to-nuclear-credit-program/
[18] Pg. 27, *U.S. Department of Energy Guidance for the Civil Nuclear Credit Program, Revision 1*, June 30, 2022. https://www.energy.gov/sites/default/files/2022-06/US%20DOE%20CNC%20Guidance-Revision%201-June%202022.pdf
[19] Analysis by the Utility Reform Network (TURN), "Diablo Canyon Extended Operations Proposal," August 23, 2022.
[20] Capped at $1.4 billion, upon subsequent legislative action
[21] Per analysis from TURN, see citation 19.

A Good Deal for Ratepayers? This bill explicitly authorizes ratepayer funds for DCPP operations during the extension period (2025-2030). Ratepayer protections are present in this bill, such as requiring that the costs to operate DCPP during the extension be reasonable and necessary, and prohibiting any ratepayer funds from being used to repay the DWR loan. This bill also attempts to have an equitable allocation of the ratepayer charge, requiring it be collected from all LSEs in CPUC's jurisdiction—which is inclusive of all CCAs and ESPs and the state's six IOUs—and that it be based on a customer's gross consumption of electricity regardless of any offset or credit status. Thus, the more electricity a customer draws from the grid, the larger their charge. This language initially raised concerns with rooftop solar advocates who characterized it as a "solar tax," before removing their opposition when clarity that "gross consumption" is only referencing consumption of electricity from the electric grid and not total energy consumption on a property.

However, this bill does take unprecedented steps to authorize various rates for all LSE ratepayers outside of a CPUC process. These include a $6.50/MWh volumetric charge for all non-PG&E LSE ratepayers, and a $13/MWh charge for all PG&E ratepayers for each MW generated by DCPP during the extension;[22] a $100 million annual fixed payment, which may be reduced by half should DCPP have extended service outages, as specified; and a $25 million per month fee, to be collected until a total of $300 million has been accrued, to pay for replacement power costs if PG&E fails to manage DCPP reasonably. All told, these charges equate to almost three-quarters of a billion dollars to be collected in the first extension year (2025-2026). The Newsom administration provided estimations that these charges should equate to roughly 10¢ per month; but the specifics of that calculation are unknown, as this charge fluctuates with the consumption of the user. In other words, for larger industrial customers that use a lot of power it is likely that their charge will be higher than 10¢ per month.

Additionally, it is unclear if these charges are intended to cover the operational costs of running Diablo, or if these charges are in addition to future CPUC-approved rates PG&E will collect to pay for the actual operations of the plant. This bill seems to contemplate the latter—that these charges are in-addition-to rates for operations—given that the bill creates a new process for how PG&E can spend the compensation for the $6.50/$13 volumetric charge. Therefore the 10¢ per month cited would not fully capture customer costs.

Under this bill, compensation from the volumetric charge cannot be paid to shareholders, but rather must be used to first meet needs at DCPP and then to accelerate, or increase spending on, broadly defined critical priorities. It is unclear what PG&E is "accelerating" relative to. This bill does prohibit PG&E from earning a rate of return for any of the accelerated work, so that no profit is realized by PG&E shareholders. However, it does not prevent PG&E from using the funding on work the CPUC previously denied as unreasonable, nor has guardrails to keep PG&E from using the volumetric fee for accelerated operations expenditures, thereby freeing-up ratepayer dollars elsewhere for capital expenditures they may earn a return on.[23]

The Newsom administration has characterized the $100 million annual management fee as the "only profit" allowed under the bill; which, given PG&E's historical profit of $150 million annually for DCPP, would be a ratepayer savings. However, the actual mechanics of how these various charges and extended rates impact customer bills, as well as PG&E shareholder return,

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[22] Roughly totals to ~$321 million annually

[23] There may be ratepayer protections in place--outside this bill--that prevent this shuffling. The committee is unaware of any such protections at the time of this writing.

remain unknown. This bill does ensure market revenues from DCPP power sales are credited back to customers. Yet, this is already the case for DCPP energy.[24] Under this bill if market revenues exceed expenses, customers outside PG&E territory may be credited up to revenue neutral, so their bill impact is zero. For those inside PG&E territory, they may receive additional credits that result in a payment. Of course, these customer credits greatly depend on the behavior of the market, which is not guaranteed to be positive.

These various funding streams, potential charges or credits, and opportunities for re-investment by PG&E make it very difficult to track the real impact on customer bills. Even the ratepayer advocates seem split in their response to the bill, with TURN citing concerns about "windfall profits" for PG&E and a lack of assurance that PG&E's spending on DCPP will be disciplined; while the CPUC's Public Advocates Office supports the bill, stating it ensures reliability, helps achieve climate goals, and provides appropriate safeguards to customers. This confusion speaks to why legislative ratemaking – which this bill undertakes – is generally best avoided when crafting energy policy. The CPUC's economic regulation is deliberative and time-consuming in order to ensure customers get the best deal for their energy. While there are some off-ramps in this legislation – such as if costs to upgrade DCPP are too high to justify an extension[25] – the current bill structure leaves many uncertainties as to whether this funding package is a good deal.

Accountability on our Clean Energy Goals. DCPP represents approximately 17% of California's GHG-free electricity, with a capacity of over 2 GWs providing baseload energy regardless of weather or time of day. And unlike other resources scheduled to come online in the coming decade, DCPP is fully operational, shielding it from many of the supply chain constraints or grid interconnection challenges. These two positive attributes – DCPP's clean electricity and availability – make sustained operations at the plant attractive for grid planners. However, the state's energy agencies have been aware since 2016 of PG&E's planned retirement of the plant. Six years have passed, and the presence of replacement resources remains uncertain. Such inaction has frustrated both legislative leaders and energy agencies alike, and leaves many to question whether the state will be in the exact same situation come 2030 and need to re-up DCPP's license yet again.

This bill recognizes the desire to limit this DCPP extension, providing explicit statutory direction that any approved extension may only be until October 2030. Moreover it takes steps to accelerate other clean-energy resources to replace DCPP, and even provides an off-ramp to the extension by allowing the CPUC to retire the plant early if new renewable energy and zero-carbon resources are built, interconnected, and determined to be adequate substitutes for DCPP. This bill also excludes DCPP from any future resource planning, either by state agencies to meet our 100% clean energy goals or by individual LSEs, thereby forcing LSEs to procure enough resources to treat DCPP as if it did not exist. The exception to this DCPP exclusion is for RA procurement compliance, where DCPP is permitted to count toward LSE obligations as a ratepayer relief measure. This bill also includes policy changes to speed up approval of transmission lines, requires the CEC to establish load shifting goals, and updates LSE planning to require additional procurement to cover more extreme climate scenarios. Finally, this bill obligates over $1 billion in future year General Fund money to support a Clean Energy

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[24] PG&E's $150 million annual profit does not arise from market sales; it is based entirely on their remaining ratebase in DCPP.
[25] Although as detailed below, the costs to upgrade will not include any environmental evaluation because the bill exempts the site from CEQA.

Reliability Investment Plan developed at the CEC to support programs and projects that accelerate the deployment of clean energy resources, demand response, assist ratepayers, and increase energy reliability. Taken together, these measures mark an enormous investment in and prioritization of clean resources, with the objective to maintain reliability while finally retiring DCPP.

Impact to Offshore Wind. The waters around DCPP have been identified in federal analyses as holding great potential for offshore wind development. In April of this year, the federal Bureau of Ocean Energy Management released environmental assessments for the Morro Bay Offshore Wind Area (MBOWA) located ~20 miles off the San Luis Obispo County coast, kick-starting what should be a multiyear process to developing wind resources there. The expectation is that any wind farm built in MBOWA would connect to the high voltage transmission lines at or near the DCPP intertie. With the CEC announcing a planning goal for offshore wind of up to 5 GW by 2030,[26] it is unclear how the DCPP extension to 2030 authorized under this bill may impact those efforts, especially as it relates to available transmission capacity.

In an August 24th letter, Offshore Wind California recognized these potential concerns with a DCPP extension, asking that such an extension – should it arise – be limited to only five years in order to minimize the impact on future resources seeking access to transmission near MBOWA. The CAISO, in its most recent transmission plan, does note that a total of ~5.3 GW of Diablo and Morro Bay offshore wind is "deliverable without major transmission upgrades."[27] It is unclear if this estimation is based off of DCPP's 2.2 GW's coming offline in 2025;[28] but even if so, ~3 GWs of transmission capacity could be available for wind throughout the extension.

An Indeterminate Halt to Environmental Review at the DCPP site. This bill "conclusively deems" any project on the DCPP site, and even the site itself, an "existing facility" for the purposes of CEQA, and does not limit this exemption to the current footprint or operations of DCPP, or any other existing or future project on the site. The key provision of the existing facilities exemption in CEQA is whether the project involves *negligible or no expansion of use.* However in this bill, that key consideration of expansion of use has been eliminated. Rather, this bill declares that any new structures, buildings, or equipment can be built and any changes to the site can be made. The legal precedent that this bill cites as justification evaluated the "negligible or no expansion of use" exemption in CEQA, but did not consider a scenario in which changes were made to the site as may be the case for DCPP's extended operations.[29]

This new statutory exemption also eliminates all the normal exceptions that must be considered prior to approving a categorical exemption. Under normal circumstances, a categorical exemption from CEQA review can be overridden if the project falls under six different exceptions.[30] The judicial case this bill cites as justification for DCPP's CEQA exemption examined only the "significant effect" exception and whether or not the replacement of existing

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[26] "CEC Adopts Historic California Offshore Wind Goals, Enough to Power Upwards of 25 Million Homes;" CEC press release; August 10, 2022; https://www.energy.ca.gov/news/2022-08/cec-adopts-historic-california-offshore-wind-goals-enough-power-upwards-25
[27] Pg. 249, 2021-2022 CAISO Transmission Plan.
[28] The CAISO analysis notes (on pg. 30) that PG&E retains deliverability options for that transmission capacity for up to three years past the current retirement date anyway; so out to 2028 currently.
[29] World Business Academy v State Lands Commission (2018) 24 Cal. App. 5th 476.
[30] Anything ranging from location near critical environmental resources to hazardous waste sites; see Section 15300.2 of Title 14 of CA Code of Regulations.

leases qualified as "unusual circumstances." This bill, however, prohibits any examination of the facts or circumstances of any DCPP project that falls within the exemption by either state agencies or the courts to determine whether any CEQA exceptions apply. Therefore this bill's treatment of CEQA is antithetical to both the spirit and the text of the categorical "existing facilities" exemption, and is more accurately characterized as an outright prohibition of CEQA review to these hundreds of acres in San Luis Obispo County.

According to the Author
According to the author, "This bill is necessary to give us an essential tool in the toolbox to prevent widespread rolling blackouts and significantly increased electricity prices from dirty carbon-emitting sources. Blackouts are a real threat and pose economic, health and safety risks, especially for the most vulnerable Californians. This bill also paves the way for greater investment in clean renewable sources, weening us of any potential need for the Diablo Canyon Power Plan. If California is able to secure sufficient renewable energy and zero carbon resources without the Diablo Canyon Power Plant being operational, there will not be any extension of Diablo beyond the preexisting closure date. However, we need to have this option available to keep the lights on and keep making progress towards net zero carbon emissions."

Arguments in Support
A coalition of ratepayer advocates (Public Advocates Office), industrial customers, utilities (Edison and SDG&E), and the City of Pismo Beach support the extension of DCPP proposed under this bill, citing the need to meet statewide reliability in the mid-term while having important customer guardrails should DCPP's extension become too expensive.

Arguments in Opposition
A coalition of ratepayer advocates (TURN), environmental organizations, scientific organizations, and environmental justice advocates oppose this bill citing inadequate ratepayer protections, the rushed timelines under which this proposal is being considered, and the host of environmental waivers granted under this bill – from CEQA to the Water Board's once-through-cooling policy. They also note the persistent seismic safety concerns with keeping DCPP online. The City of San Luis Obispo did file a letter of concern, citing uncertainty to offshore wind development should DCPP be extended.

FISCAL COMMENTS

Partially unknown. This bill appropriates over $2.5 billion in current and future year General Fund dollars. However, the current version of this bill has not received review from either Appropriations Committee to determine the full fiscal impact on the state budget.

VOTES

SENATE FLOOR: Vote Not Relevant
YES:
ABS, ABST OR NV:

ASM GOVERNMENTAL ORGANIZATION: Vote Not Relevant
YES:
ABS, ABST OR NV:

UPDATED

VERSION: August 28, 2022

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